

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA



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Application of Pacific Gas and Electric
Company Proposing Cost of Service and
Rates for Gas Transmission and Storage
Services for the Period 2015 - 2017 (U39G).

Application 13-12-012
(Filed December 19, 2013)

And Related Matter.

Investigation 14-06-016

**COMMENTS OF
THE OFFICE OF RATEPAYER ADVOCATES
ON THE PROPOSED DECISION OF
ADMINISTRATIVE LAW JUDGE AMY YIP-KIKUGAWA**

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I. INTRODUCTION

Pursuant to Rule 14.3 of the Commission's Rules of Practice and Procedure, the Office of Ratepayer Advocates (ORA) submits these Opening Comments to the Proposed Decision (PD) of Administrative Law Judge (ALJ) Amy Yip-Kikugawa in the above-captioned matter.

The PD authorizes a base revenue requirement increase of \$377 million,¹ for a Test Year 2015 revenue requirement of \$1,108 million, reflecting an approximately 51 percent increase over present rates and 68 percent of Pacific Gas and Electric Company's (PG&E) requested increase. This amount is adjusted downward by \$164 million in 2015 due to the disallowance for improper ex parte contacts, leading to an authorized revenue requirement of \$944.984 million, or an increase of \$299.605 million for the 2015 Test Year.² The total impact is a 32.1 percent increase over present rates,³ or 40 percent of the \$571.5 million increase PG&E was requesting for the Test Year.⁴

For 2016 and 2017, the PD would authorize post-test year revenue increases of \$237 million and \$126 million, respectively, over the prior year. If adopted, the PD approves a cumulative increase of \$593.5 million, or 83 percent, over the three-year Gas Transmission & Storage (GT&S) Rate Case period, which would be even higher without the ex parte disallowance.

The PD's reliance on the \$164 million ex parte disallowance as a significant rate making adjustment in this case is concerning. As set forth in the comments below, the record reflects that many other adjustments could have and should have been made, but were not. The Commission should make the proper rate determinations in this case based on the evidence adduced, without taking into account the impacts of either the ex parte disallowance or the \$850 million in San Bruno penalties. Both adjustments should be made after the Commission reaches a determination, based on the record, of the reasonableness of the rates proposed by PG&E.

ORA's Comments address only the areas in the PD where there are legal, factual, or technical errors. The Commission should not construe ORA's silence on a particular issue as assent

¹ See PD, Appendix C, line 1.

² PD, p. 2.

³ PD, p. 1.

⁴ PD, p. 2.

on that issue. ORA recommends that the final decision the Commission adopts in this proceeding include the changes described in these Comments and in Appendix A.

II. LEGAL ISSUES

A. Burden of Proof and Standard of Proof

The PD notes that PG&E, as the applicant, “must meet the burden of proving that it is entitled to the relief sought in this proceeding”⁵ and “the burden of affirmatively establishing the reasonableness of all aspects of the application.”⁶ The PD asserts that utility rates are “just and reasonable” pursuant to Public Utilities Code § 451 “when they ‘have been **prudently** incurred by competent management exercising the best practices of the era, and using well-trained, well-informed and conscientious employees and contractors who are performing their jobs properly.’”⁷ The PD then goes on to say that “[w]ith the burden of proof placed on PG&E, the Commission has held that the standard of proof PG&E must meet is that of a preponderance of the evidence.”⁸

B. Public Utilities Code § 1705 Requirements

Public Utilities Code § 1705⁹ requires that Commission decisions “shall contain, separately stated, findings of fact and conclusions of law by the commission on all issues material to the ... decision.” Among other things, absent separately stated findings of fact and conclusions of law, parties in a proceeding, and a reviewing court, have no ability to determine whether the Commission has engaged in reasoned decision making.¹⁰ Further, as observed by the California Supreme Court: “Findings on material issues can also serve to help the commission avoid careless or arbitrary action. “Often a strong impression that, on the basis of the evidence, the facts are thus-and-so gives way when it comes to expressing that impression on paper.”¹¹

⁵ PD, p. 20.

⁶ PD, p. 20.

⁷ PD, pp. 20-21, citing *Decision Implementing a Safety Enhancement Plan and Approval Process for San Diego Gas & Electric Company and Southern California Gas Company; Denying the Proposed Cost Allocation for Safety Enhancement Costs; and Adopting a Ratemaking Settlement (Sempra PSEP Decision)* [D.14-06-007] at 31 (emphasis added).

⁸ PD, p. 21.

⁹ Unless otherwise noted, all further section references are to the California Public Utilities Code.

¹⁰ *Cal. Motor Transport Co. v. CPUC*, 59 Cal. 2d 270, 274-275 (1963).

¹¹ *Cal. Motor Transport Co. v. CPUC*, 59 Cal. 2d 270, 274-275 (1963) quoting 2 Davis, Administrative Law

The PD errs by failing to provide findings of fact and conclusions of law on multiple material issues, and by making findings of fact and conclusions of law that are contradicted by the text of the PD. Given limitations of space and time, the following comments address some, but not all, of those errors, with a focus on areas where the rate increases are most significant.

**C. The Proposed Decision Would Adopt a Policy
In Conclusion of Law 2 Contrary to the Utility’s Obligation
to Provide Safe and Reliable Service
at Just and Reasonable Rates**

Despite the definition of just and reasonable costs in the PD as being those “prudently incurred by competent management,”¹² the PD would adopt a policy as follows in Conclusion of Law 2: “PG&E’s forecast costs are not unreasonable and subject to ratemaking disallowance simply because its management **imprudently** delayed or deferred work.”¹³ This policy is the antithesis of a sound and rational safety policy and equitable ratemaking. This policy provides a direct signal to PG&E and other utilities that they are no longer required to show the reasonableness of their actions to gain cost recovery, and they can be financially rewarded if they are instead imprudent and fail to perform necessary maintenance and safety related work on their systems. The new policy in Conclusion of Law 2 provides an incentive for PG&E and other utilities to defer necessary maintenance and safety related work, since there would be no regulatory consequences to delay.

The policy of the PD is in sharp contrast to the Commission’s prior policies regarding deferred maintenance. In 1982, the Commission set forth a clear and coherent standard regarding the issue of deferred maintenance when it stated:

For us to authorize Edison’s recovery of deferred maintenance expense would establish an undesirable precedent, whereby the utility is effectively guaranteed that it can earn (or exceed) its authorized rate of return, regardless of its operating efficiency or inefficiency, simply by curtailing current maintenance activities, in assurance that they could be refinanced later through recovery of deferred maintenance expenses in a succeeding rate case. This would create a perverse incentive for the utility to defer needed

Treatise (1958) § 16.05, quoting Judge Frank in *United States v. Forness*, 125 F.2d 928, 942, cert. denied 316 U.S. 694 (internal citations omitted or shortened).

¹² PD, pp. 20-21.

¹³ PD, COL 2, p. 411 (emphasis added). PG&E has the affirmative burden of showing that their rates and costs are just and reasonable; that rates “are not unreasonable” is not an equivalent finding to an initial finding.

maintenance in the future. Consequently, we will disallow recovery of \$34.6 million requested for deferred maintenance activities in 1983 and 1984. Our disallowance of this expense for test year ratemaking purposes does not relieve Edison of its responsibility to maintain the operating efficiency of its utility plant in a timely manner. Indeed, we expect Edison to fulfill that responsibility more conscientiously in the future.¹⁴

The policy adopted in Conclusion of Law 2 of the PD regarding delayed or deferred work should be eliminated in its entirety, and only reevaluated with appropriate modifications adopting a clear standard similar to the one set forth by the Commission in D.82-12-055. Furthermore, the PD should be modified to eliminate all ratepayer funding for delayed and deferred maintenance that was funded in the PD.

III. FACTUAL AND TECHNICAL ISSUES

A. Safety and Risk Management – Conclusion of Law 5 and Ordering Paragraph 2 Should Be Modified to Clarify that the PD Does Not Prejudge the Issues Raised Regarding PG&E’s Risk Assessment Model

The PD errs in reaching Conclusion of Law 5, which stated that “PG&E’s proposed risk management approach and asset family categories are reasonable.”¹⁵ PG&E’s risk management approach was substantially the same as in its 2014 GRC. The Commission concluded in D.14-08-032 that the risk showing did not constitute a “risk assessment” for numerous reasons, but most importantly for the lack of any quantification of risk reduction for the money spent. D.14-08-032 was decided months after PG&E filed this rate proceeding in December 2013.

ORA,¹⁶ TURN, and Indicated Shippers all provided significant amounts of evidence showing that PG&E’s proposed risk management approach was *not* reasonable and had many shortcomings. ORA explained that given these shortcomings, PG&E’s risk assessment model should be considered an “alpha version” in a long iterative process:

PG&E’s internally-developed risk assessment model is not sufficiently quantitatively rigorous to determine that specific projects are just and reasonable. The Commission should view PG&E’s current risk assessment and associated metrics as the “alpha version” and first iteration of what

¹⁴ D.82-12-055, 10 CPUC 2d 155, 186; (1982).

¹⁵ PD, p. 411, Conclusion of Law 5.

¹⁶ See Ex. ORA-53 (Skinner), Safety and Risk Management (Corrected Version); Ex. TURN-2; and Ex. IS-2 through IS-8. ORA Testimony on risk issues spans 13 pages, and 5% of its Opening Brief was devoted to this issue, yet the PD fails to mention ORA’s position or arguments on this issue.

will be a years-long (if not decades-long) process of determining methods and models to quantify risk, risk-reduction, and cost-effectiveness of mitigations.¹⁷

The Safety and Enforcement Division's (SED) Final Staff Report (SED Report)¹⁸ also found flaws with PG&E's approach, including: (1) there was no determination of incremental risk reduction values for various risk mitigation programs;¹⁹ (2) allocation of funding was subjective;²⁰ (3) the index scoring method has known flaws;²¹ (4) inadequate rigorous consideration of interacting threats other than earth movement with construction defects;²² (5) no quantification of risk tolerance;²³ and (6) insufficient documentation of PG&E's basis for selecting alternative mitigation approaches.²⁴ SED also found that PG&E's approach no longer plans Pipeline Safety Enhancement Plan (PSEP) work separate from its base work and concludes that "it is important that PG&E be able to track and readily identify the specific drivers for any given project within a workstream."²⁵

The PD errs as a matter of law by failing to address the similar observations by numerous parties that PG&E's model fails to properly ascertain risk in terms of the dollars proposed in the rate case.²⁶ The PD ignores the views on this issue expressed by ORA and SED, whose report, while not subject to cross-examination, quite thoroughly criticized the PG&E approach, pointedly noting that the choice of spending level was subjective and not based on the model. Instead of addressing this evidence, the PD briefly summarizes elements of the Indicated Shippers' showing and concludes that

¹⁷ Ex. ORA-53 (Skinner), Safety and Risk Management (Corrected Version), p. 1.

¹⁸ The SED Report is included in the proceeding as a reference document. *See* 12 RT 751 to 752.

¹⁹ SED Report, p. 21.

²⁰ SED Report, pp. 21-22.

²¹ SED Report, p. 22-23.

²² SED Report, pp. 23-24.

²³ SED Report, pp. 24-25.

²⁴ SED Report, p. 25.

²⁵ SED Report, p. 32.

²⁶ The Commission cannot make a determination of reasonableness without considering the evidence and providing findings and conclusions regarding the issue. "Though it is within the discretion of the commission to determine the factors material to public convenience and necessity, *section 1705* requires it to state what those factors are and to make findings on the material issues that ensue therefrom." *Cal. Motor Transport v. PUC*, 59 Cal. 2d 270, 275 (1963) (*citations omitted; emphasis in original*).

it “agree[s] ... that many of the concerns Indicated Shippers has raised ... shall be considered within the scope of PG&E’s S-MAP application and we should not prejudge those issues here.”²⁷

The PD then errs again when it ignores its own correct determination against prejudgment and concludes that “PG&E’s proposed risk management approach ... [is] reasonable.”²⁸ This error is compounded by the PD failing to acknowledge or address the importance of the Commission’s Finding of Fact 10 in Decision 14-08-032 on PG&E’s 2014 General Rate Case, which stated “[t]he Liberty consultants found that the expectations created in the Executive Director’s March 5, 2012 letter anticipate a use of risk assessment that is beyond what one currently finds in the industry.” PG&E has stated it did not change its GT&S filing as a result of the GRC proceeding,²⁹ and thus the risk analysis continued to fail to meet the Commission’s standards. The Commission in D.14-08-032 explicitly tied a “risk assessment” to measuring reduction of risk per dollar spent.³⁰ The Commission must consider the evidence adduced by Indicated Shippers, ORA, TURN, and SED’s analysis in reaching the conclusion that PG&E’s risk management approach is “reasonable” for determining the cost of its service, or the choice of particular projects.³¹ The “reasonable” language in Conclusion of Law 5 and Opening Paragraph 2 should be struck and a new Conclusion of Law should be added to reflect the PD’s appropriate conclusion that issues regarding PG&E’s risk management model will not be prejudged in this proceeding. The proposed revisions are set forth in Attachment A hereto.

B. Ratemaking Issues

The final decision should accept ORA’s proposal for a four-year rate cycle given that the delayed outcome of this proceeding caused by PG&E’s ex parte violations would leave only a handful of months before PG&E will make its next GT&S filing, while PG&E and ORA have already been preparing the 2017 PG&E GRC, scheduled for hearings in less than three weeks.

²⁷ PD, p. 26.

²⁸ PD, COL 5.

²⁹ See Ex. ORA-61, p. A-47; Citing PG&E Data Response to ORA Question 23-6.

³⁰ D.14-08-032, p. 29.

³¹ The PD’s discussions resolving the reasonableness of the costs and requested projects never invoke explicitly PG&E’s risk model in reaching its decisions.

C. Transmission Pipe

PG&E's requests for Hydrotest Program expenses and Vintage Pipeline Replacement (VPR) Program capital expenditures comprise the largest expense program (Hydrotest) and capital expense program (VPR) in the GT&S application. The PD erred in its determination approving unit cost forecasts for both of these programs, as set forth below. As described below, the PD also errs by overestimating the number of digs per project for External Corrosion Direct Assessment (ECDA), by not relying on PG&E's lower rebuttal testimony forecast for Public Awareness Programs, and by determining that PG&E's extensive history of deferring maintenance on corrosion – a time-dependent threat – is not unreasonable.

1. Direct Assessment – The PD Errs in Calculating Digs Per Project

The PD errs in calculating the digs per project ratio for External Corrosion Direct Assessment.³² While the PD correctly finds that “PG&E's forecast dig-to-project ratio is overstated as a result of rounding,”³³ and that there can be partial digs over multi-year projects and use of fractional digs for ratemaking purposes,³⁴ the PD's use of averaging the annual dig per project ratio back to 2004 undermines these conclusions and leads to further errors. A simple calculation of all digs to all projects utilizing the full historical data set of 2004-2013 yields a total of 1173 digs across 203 projects, for an average of 5.78 digs per project over the time period, not the 6.02 ratio the PD determines.

The PD fails to recognize that the primary rationale behind ORA's recommendation of the 2013 dig-project ratio was to match PG&E's use of only 2013 unit costs for its unit cost forecast,³⁵ a figure that has been implicitly adopted in this proceeding.³⁶ But ORA and the PD also recognized that use of a 4.5 dig/project ratio was almost identical the 4.43 ratio for the longer-term 2008-2013 period (633 digs for 143 projects). The PD mistakenly claims its recommendation of a

³² PD, pp. 47-48.

³³ PD, p. 47. PG&E rounded any fraction of a dig up to the next higher number to calculate an annual ratio, and then rounded any fraction of an average of such annual averages to the next-highest number, in its forecast.

³⁴ PD, p. 47.

³⁵ Ex. ORA-7, p. 10. *Also see*, Ex. ORA-65, p. 31.

³⁶ PD, p. 48. The PD adopts a 2015 forecast of \$25.958 million, a reduction from PG&E's forecast of \$28.336 million, based on the lowered digs-to-project ratio.

6.02 dig/project ratio is “consistent with PG&E’s experience between 2008 and 2013.”³⁷ The 6.02 average is not as consistent with PG&E’s experience between 2008 and 2013,³⁸ as compared to the 4.5 average. As shown in Figure 1 below, analysis of the 2008 to 2013 period results in 143 projects across 633 digs, or an average of 4.43 digs per project which is below ORA’s forecast of 4.5 digs per project. The median of this data reveals a similar trend – 4.68 digs per project from 2004-2013, and 4.35 digs per project from 2008-2013. The PD should utilize the actual dig to project ratio from 2013 to match the use of 2013 costs and because of its similarity to the actual 2008-2013 ratio, and reject use of the oldest data that will likely provide PG&E with an unreasonable windfall.

Given that ORA’s forecast number of digs per project is higher than PG&E’s actual digs per project for four out of the six years, it is reasonable to assume no impact to safety would result from a lower forecast than PG&E’s estimates given the data integration requirements associated with federal regulations.³⁹

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³⁷ PD, p. 48.

³⁸ PD, p. 48.

³⁹ See, 49 Code of Federal Regulations 192, Subpart O – Gas Transmission Pipeline Integrity Management.

Figure 1 – ECDA Data

Year	Project	Digs	Avg Digs / Proj (rounded up)	Avg Digs / Proj (not rounded)
2004	6	49	9	8.17
2005	9	91	11	10.11
2006/2007	45	400	9	8.89
2008	8	32	4	4.00
2009	19	108	6	5.68
2010	19	89	5	4.68
2011	24	102	5	4.25
2012	49	195	4	3.98
2013	24	107	5	4.46
Avg Per Project Per Year			7	6.02
Avg Digs per Project (2004 through 2013)				
Total # of Projects		# of Digs	Avg Digs / Proj (rounded up)	Avg Digs / Proj (not rounded)
203		1173	6	5.78
Avg Digs per Project (2008 through 2013)				
Total # of Projects		# of Digs	Avg Digs / Proj (rounded up)	Avg Digs / Proj (not rounded)
143		633	5	4.43
2004-2013 Avg Digs / Project (not rounded, Median)				4.68
2008-2013 Avg Digs / Project (not rounded, Median)				4.35

2. Hydrostatic Testing

a) ORA Made a Comprehensive Showing that PG&E's Forecast Was Unreasonable and the PD Errs by Ignoring This Evidence

PG&E's requested hydrotest⁴⁰ unit cost in this case is double its request for the Pipeline Safety Enhancement Plan (PSEP), even though the PSEP unit cost was deemed "at the high end of the range of reasonableness" by the Commission.⁴¹ In response, ORA made a comprehensive showing based on substantial evidence that PG&E's hydrotest unit cost forecast is unreasonable because: (1) while PG&E repeatedly argued that actual costs should be used to develop forecasts, its hydrotest unit cost was based on forecasted costs so that PG&E's statements were inconsistent with

⁴⁰ For purposes of these comments, pressure testing and hydrotesting may be used interchangeably. Both terms are intended to indicate the process of testing the fitness for service of pipelines by increasing the pressure within a pipeline to reveal if substantial defects exist.

⁴¹ ORA Opening Brief (OB), p. 31 and D.12-12-030, pp. 63 and 125.

its showing;⁴² (2) PG&E's forecast unreasonably failed to reflect a trend of falling unit costs in 2011, 2012 and 2013 resulting from longer tests and efficiency gains;⁴³ and (3) PG&E's cost data included PSEP-specific startup and other costs that will not be incurred during the rate case period.⁴⁴ The PD ignored this evidentiary showing and finds PG&E's hydrotest unit cost forecast is "reasonable and should be adopted."⁴⁵

This PD finding of reasonableness is error because it mischaracterizes ORA's showing in some places, ignores uncontroverted evidence showing that PG&E's forecast was overstated, and is inconsistent with the PD's acknowledgment that PG&E's hydrotest costs "should decrease over time as the result of efficiency gains and non-emergency nature of the work (as opposed to PSEP)..."⁴⁶ The PD also errs by failing to provide "separately stated, findings of fact and conclusions of law" to support its finding of reasonableness.⁴⁷ If the PD were to address all of the evidence in separately stated findings, as required by § 1705, it would become evident that the reasonableness finding has no support.⁴⁸

b) The PD Ignores the Point that Use of Forecasted Costs is Unreasonable when PG&E Repeatedly Testified to the Superiority of Actual Costs

PG&E repeatedly testified to the reasonableness of its forecasts based on its reliance on 2013 *actual costs*.⁴⁹ ORA calculated that over 92% of PG&E's costs included in the hydrotest unit cost forecast were based on forecasts.⁵⁰ The record shows that 2013 *actual costs* result in a unit cost of \$840,000 per mile, a more than 15 percent reduction compared to PG&E's forecast.⁵¹ Given

⁴² ORA OB, pp. 33-35.

⁴³ ORA OB, pp. 35-50.

⁴⁴ ORA OB, pp. 56-57.

⁴⁵ PD, COL 19 at p. 412.

⁴⁶ PD, p. 58.

⁴⁷ Public Utilities Code § 1705. *See also Cal. Motor Transport Co. v. CPUC*, 59 Cal. 2d 270, 274-275 (1963).

⁴⁸ *See* Note 11 above and accompanying text.

⁴⁹ *See* ORA OB, pp. 33-34 with over 10 citations to the record, and discussion of digs per project, *supra*, in Section 3.A.1.C of these Comments.

⁵⁰ *See* Ex. ORA-34, pp. 14-19 and ORA OB, pp. 34-36.

⁵¹ Ex. TURN-4, p. 27. PG&E rebuttal testimony states that the more current data results in a unit cost of \$.85 million per mile. *See* Ex. PG&E-39 (Rebuttal Testimony), p. 4A-53. $\$.97/\$.84 = 1.154$ or a 15.4% increase.

PG&E's testimony in support of using actual costs for forecast purposes, the evidence clearly supports a finding that PG&E's 2015 expense for hydrotest should be *no more than* \$840,000 per mile – based on its reported actual costs – and should be less to account for falling costs due to longer length hydrotests in 2016 and 2017.

While the PD mentions these points in its summary of intervenor arguments, it commits legal error by failing to discuss why forecast data for 2013 should trump the use of actual costs.⁵² The PD also states that PG&E's forecast is “based on three years of actual experience.”⁵³ This statement is incorrect given that PG&E's forecast is based on a *forecast* of 2013 costs, even when actual costs became available – and therefore is not based on actual experience. Finally, the PD references PG&E's assertion that “there are high variable costs or costs at a project level that cannot be accurately predicted...” as justification for adopting PG&E's proposed unit cost.⁵⁴ This rationale is factual error because, consistent with PG&E's testimony regarding the value of a “programmatic” approach,⁵⁵ such uncertainties are captured in the actual costs for 2011-2013, and reflected in an actual cost forecast.

**c) The PD Errs by Relying on PG&E's Argument
for Rising Costs Rather than ORA's Evidence of
Falling Costs**

ORA provided substantial evidence that PG&E's hydrotest unit costs are reasonably expected to decrease during the rate case period due to longer length hydrotests in 2016 and 2017, six potential sources of going forward efficiency gains, and a projection based on the economic principal of an “experience curve.”⁵⁶ The PD acknowledged the theme of these arguments and “generally agreed” that “hydrostatic costs should decrease over time.”⁵⁷ However, the PD then errs by declining to reduce PG&E's forecast because “the potential level of decrease is unknown at this time.”⁵⁸ The PD further errs by justifying approval of PG&E's forecast by citing to a much higher

⁵² PD, pp. 52-53 and 58.

⁵³ PD, p. 57, *emphasis added*.

⁵⁴ PD, p. 57.

⁵⁵ ORA OB, pp. 29-31. *See especially* the footnotes to PG&E testimony found there.

⁵⁶ ORA OB, pp. 38-42.

⁵⁷ PD, pp. 52-53 and 57.

⁵⁸ PD, pp. 58.

PG&E 2015 forecast of \$1.86 million per mile.⁵⁹ That forecast, provided in PG&E's Rebuttal Testimony, was the result of a curve-fitting exercise that is not supported by general economic theory or factual reality.⁶⁰ PG&E's analysis also used cost data from 2014 that was shown to be anomalous due to "shorts"⁶¹ when compared to the projected scope of GT&S.⁶² The result is that while PG&E's hydrotest costs should be adjusted downward to account for falling costs in all three years of the rate case cycle, PG&E will instead collect more revenue as costs fall.

d) The PD Fails to Address ORA's Uncontested Showing that Hydrotest Projects Will Grow Longer Over the Rate Case Period with Lower Unit Costs Resulting

The PD mischaracterizes ORA's showing regarding the length of PG&E's future projects, stating: "[ORA] further notes that the project lengths during the Rate Case period are projected to be similar in length to the projects conducted in 2013."⁶³ ORA presented evidence that hydrotests will be significantly longer in 2016 and 2017, resulting in lower unit costs. Despite this evidence, the PD finds PG&E's forecast, which does not take these changes into account, reasonable.⁶⁴

The PD commits legal error by failing to address ORA's showing that PG&E expects the length of its hydrotests to increase each year of the rate case cycle from 2.5 miles in 2013 to 2.67 miles in 2015, to 3.51 miles in 2016 and 4.19 miles in 2017.⁶⁵ Since PG&E agrees that longer hydrotests result in lower unit costs,⁶⁶ hydrotest unit costs should be adjusted to account for

⁵⁹ PD, pp. 58.

⁶⁰ ORA OB, pp. 38-42.

⁶¹ PG&E acknowledged that 2014 contained "shorts" resulting in "upward cost pressures" for that year 17 RT 1736:15-26 (Barnes/PG&E) ("And so what we see is in 2014, quite a few -- we were attacking, if you will, quite a few what we call shorts. So mini projects, short in length, as opposed to most of the projects leading up to 2013 were -- were less projects much longer in length. So we actually had some efficiencies associated with the length of the project. So when we roll into 2014, what we now ... know 2014 is the actual unit costs for 2014 has actually gone up to \$1.2 million a mile.").

⁶² Ex. PG&E-39, pp. 4A-49 to 4A-51. PG&E provided no evidence that the "polynomial curve fit" it used has any basis in economic theory, and its use of a "power curve fit" which is reflective of an "experience curve" illustrated that 2014 was an outlying data point.

⁶³ PD, p. 53.

⁶⁴ PD, p. 58.

⁶⁵ ORA OB, p. 44 and footnote 154.

⁶⁶ 17 RT 1751:19-26 (PG&E/Barnes).

the fact that PG&E's hydrotest costs will fall over the rate case period in both 2016 and 2017. Instead, PG&E's budget will increase each year due to attrition.

**e) The PD Errs by Ignoring Deficiencies in
PG&E's PSEP Compliance Reports**

The PD correctly acknowledges that PG&E's forecast includes costs that were not included in the quarterly PSEP Compliance Reports (Reports).⁶⁷ However the PD then errs by using PG&E's cost data rather than PSEP Report data in its adopted forecast. While the PD acknowledges ORA's argument that D.12-12-030 clearly intended the reports to include all PSEP costs, it fails to recognize ORA's evidence that over \$100 million of the costs that were not recorded in the PSEP reports (but added to PG&E's forecast) are unique to PSEP and unlikely to be incurred in GT&S. This error is further evidence that the adopted PG&E forecast is overstated.⁶⁸

f) The PD Fails to Comply With § 1705

As discussed in the "Legal Issues" Section above, § 1705 requires that Commission decisions "shall contain, separately stated, findings of fact and conclusions of law by the commission on all issues material to the ... decision." The concerns expressed by the *California Motor Transport*⁶⁹ court are especially relevant regarding the PD's finding that PG&E's hydrotest forecast is reasonable. As set forth above, and in ORA's Opening and Reply Briefs, PG&E failed to meet its burden of proving that its 2015 hydrotest unit cost forecast was reasonable.

The PD does not justify the reasonableness of PG&E's forecast and none of its Findings of Fact or Conclusions of Law address these highly litigated issues, which included over a week of cross examination. These omissions are legal error, which, if corrected, should lead to adoption of a unit cost forecast of no more than \$840,000 per mile, based on actual costs.

The forecast of \$840,000 per mile is at the high end of reasonable given that the evidence shows that PG&E's unit costs will go down due to longer length hydrotests and continuing efficiency gains during the rate case period. Consequently, the forecast is more than enough to ensure that PG&E is able to perform the full scope of work it has proposed. Overcollections for 2016 and 2017 should easily ensure against the unlikely event of an undercollection for 2015 work.

⁶⁷ PD, p. 53.

⁶⁸ ORA Opening Brief, pp. 56-57.

⁶⁹ *Cal. Motor Transport Co. v. CPUC*, 59 Cal. 2d 270, 274-275 (1963).

**g) The PD Errs By Allowing PG&E to Recover
Costs to Hydrotest 97 Miles Installed After July
1, 1961**

While the PD finds that PG&E shareholders are responsible for all post-1956 hydrotest costs where records are missing,⁷⁰ it then contradicts itself by declining to disallow costs associated with 97 miles of pipe installed after July 1, 1961 on the basis that PG&E has “confirmed its commitment” not to charge customers for this work.⁷¹ Such a contradiction is legal error which should be clarified to reflect disallowance of such costs in PG&E’s revenue requirement.

3. Vintage Pipe Replacement Program

**a) The PD Errs by Adopting a VPR Forecast
Based on Factual Errors and an Arbitrary
Determination to Combine the Large and
Medium Pipe Forecasts**

The PD provides \$505.8 million for the Vintage Pipe Replacement Program (VPR) for the period 2015-2017. While this is a reduction of \$90.7 million compared to PG&E’s request for \$596.5 million, the PD relies on errors of fact as described in the sections below that need to be corrected. ORA provides a revised forecast below that corrects these errors while incorporating reasonable adjustments ordered in the PD. Corresponding revisions to the PDs, Findings of Fact (FOF), and Conclusions of Law (COL) are provided in Appendix A.

**b) The PD Errs and Contradicts Itself by Using a
Unit Cost for Large Pipes That Is Based Solely
on One Pipeline in the Highest Cost Location of
PG&E’s Service Territory**

The PD correctly concludes that PG&E’s use of only high cost Line 109 (L-109) PSEP projects to calculate the unit cost for large pipes is unreasonable. Conclusion of Law 34 states: “PG&E’s assertion that Line 109 is representative of all expected VPR projects is unconvincing.”⁷² Conclusion of Law 37 elaborates:

We find that it is unreasonable to adopt a forecast based on nine PSEP projects, especially when it appears that a larger number of PSEP projects would have met the selection criteria. We find that PG&E’s selection of a

⁷⁰ PD, p. 58.

⁷¹ PD, p. 60.

⁷² PD, COL 34, p. 414.

small number of projects in congested areas has resulted in unit costs that are not representative of the work to be performed in the VPR Program during the Rate Case Period.⁷³

However, the PD then proceeds to establish a unit cost based only on projects used in both PG&E and ORA forecasts⁷⁴ – which still only includes projects from Line 109 for large diameter pipes. Because PG&E excluded PSEP projects on nine large diameter pipelines other than L-109, these projects are not included in the unit cost used by the PD.⁷⁵ ORA’s revised forecast below corrects this error by including these other large pipes in the forecast, thus making the forecast consistent with the PD’s conclusions that PG&E’s sole reliance on L-109 projects for determining large pipe unit costs is unreasonable.

c) The PD Arbitrarily Groups Medium Pipes Together with Large Diameter Pipes to Arrive at a Blended Unit Cost

The PD blends forecasts of medium and large diameter pipes to adopt one unit cost of \$7.985 million per mile for all pipes 12” in diameter or greater.⁷⁶ The PD states that this is in response to a discrepancy it noted regarding 24” pipe, but fails to provide an explanation of why this is the most reasonable way to address that discrepancy.⁷⁷ Review of the record, which is based on three groupings of pipes by diameter - small, medium, and large - shows that grouping medium and large pipes together is arbitrary. While there is a question about whether 24” diameter pipe should be treated as medium or large pipe with respect to unit costs, no party suggested that medium diameter pipes should have the same unit cost as large pipes. To the contrary, both ORA and PG&E’s analyses showed that replacement costs for medium pipes are comparable to small diameter pipes.⁷⁸ By combining medium and large pipes together, the PD provides an inflated budget for

⁷³ PD, COL 37, p. 414. *See also* COL 38.

⁷⁴ PD, p. 81.

⁷⁵ Ex. ORA-131, tab “ITD cost, no betterment”, lines 48-52, 56, 65, and 67.

⁷⁶ PD, p. 82.

⁷⁷ PD, p. 82.

⁷⁸ PD, p. 75, Table 9. PG&E’s analysis shows medium pipe costs being 9.4% higher than small pipe costs while ORA’s analysis shows them having the same costs. The PD’s analysis would increase medium (12” – <24”) pipe costs by approximately 38% compared to using PG&E’s proposed \$5.8 million/mile unit cost.

2015 by incorrectly applying a higher cost to medium pipes. ORA's revised forecast provided below addresses this issue by calculating separate unit costs for both medium and large diameter pipes.

**d) The PD Errs by Establishing VPR Unit Costs
Using PSEP Costs that Are Not Likely to be
Incurred in GT&S Projects**

The PD relies upon Exhibit ORA-131 as the source of its unit costs.⁷⁹ The PD fails to acknowledge that this exhibit provides two sets of unit cost calculations: one based on project costs provided by PG&E in response to discovery and another using project costs provided by PG&E in the PSEP Quarterly Reports. The PD acknowledges the two data sources in its discussion of hydrotest costs, but fails to do so regarding VPR, even though the same issues exist for both programs.⁸⁰ For VPR, the PD uses the calculations based on PG&E's higher project costs, rather than the costs provided in the PSEP Reports. The source of the cost data has a much smaller impact on the VPR program compared to the hydrotest program.⁸¹ ORA's revised forecast below uses the unit cost calculations based on PG&E's cost data, consistent with the PD methodology.

However, ORA continues to note that this PG&E cost data contains PSEP costs that will not be incurred during this rate case cycle, thereby overstating the actual costs to be incurred between 2015 and 2017. Consequently, ORA's use of PG&E's cost data herein should not be construed as support for PG&E's cost data or support for the PD's use of the data. As set forth in Section 4 below, it is critical that PG&E's incomplete cost reporting for pressure test and pipe replacement be remedied going forward to facilitate future forecasting and identification of opportunities for cost savings.

**e) The PD Errs by Adopting a Three Year Budget
Based on the Highest Annual Cost**

ORA's testimony discussed two reasons why annual VPR costs would decline over the rate case period: the forecasted miles replaced declined each year, and the projects were in progressively

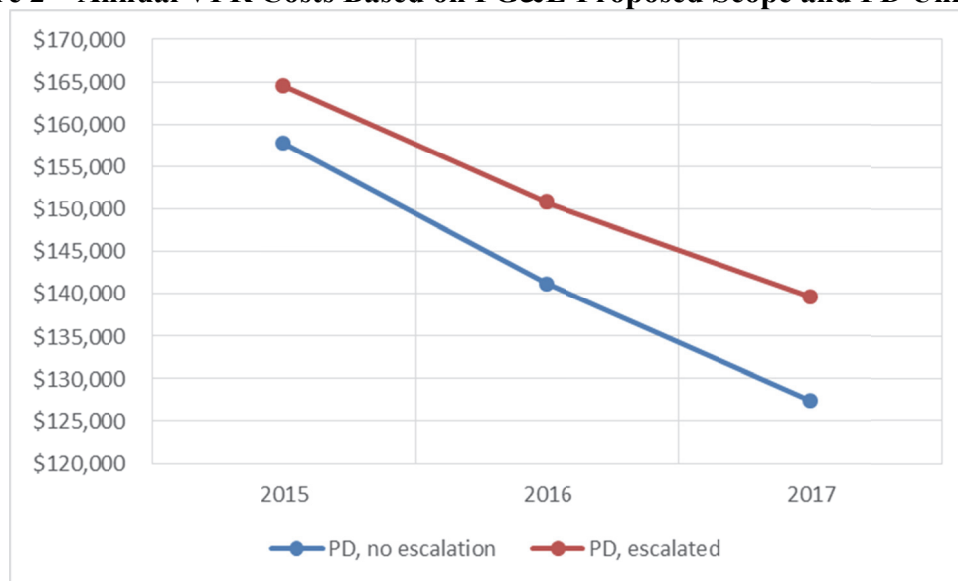
⁷⁹ PD, p. 81.

⁸⁰ PD, p. 53.

⁸¹ Per Ex. ORA-131, the difference in unit costs for the same common projects is 10.2% for small pipes ; <1% for medium pipes; and 2.2% for large pipes, using PG&E's cost in the denominator. See rows 22, 45, and 69.

less congested, and therefore less expensive, locations.⁸² As shown in Figure 2 below, this trend of falling costs is confirmed using annual cost forecasts provided in calculations supporting the PD.⁸³

Figure 2 – Annual VPR Costs Based on PG&E Proposed Scope and PD Unit Costs



The PD errs by establishing a three year budget starting with the highest annual cost for all three years, \$164.535 million, and then applying attrition rates on top of this for 2016 and 2017, resulting in increasing, rather than decreasing unit costs. ORA’s revised forecast provided below does not account for this error for several reasons discussed below.

f) ORA’s Revised Forecast Should be Adopted Because it Implements the PD’s Determinations While Correcting Factual Errors

ORA continues to support its original forecast of \$323.1 Million for 2015-2017, which results in a VPR budget of \$352.9 million when the PD’s escalation and stipulated attrition adjustments are applied. However, ORA proposes that the PD adopt the revised forecast here to account for the errors discussed above. To address these errors, ORA made the following adjustments to the cost calculator supporting the PD:

⁸² Ex. ORA-34, Table 4C-16, p. 54, and Figure 4C-3, p. 52.

⁸³ Ex. ALJ-1, file “PD Vintage Pipe Replacement – Capital.xls.” Cell H13 of this workpaper shows the unescalated 2015 cost to be \$153.743 million. Unescalated values for 2016 and 2017 were determined by filtering projects based on “Approx. Year Planned,” Column G, and summing the “Unescalated Forecast” values in Column N. Escalated values in this chart apply the escalation and attrition rates used in the PD: 4.4% for 2015, 2.3% for 2016, and 2.6% for 2017.

- GT&S projects were assigned to one of three groups based on the diameter ranges shown in Table 7 of the PD; and
- The following units costs were applied to each project based on PG&E discovery data in Exhibit ORA-131 except as noted below:⁸⁴
 - Small pipes (<12” diameter): \$4.51 million per mile;
 - Medium pipes (≥12” to <24” diameter): \$3.67 million per mile; and
 - Large pipes (≥24” diameter): \$7.25 million per mile.

The unit costs for small and medium pipes use the method described in the PD: PG&E costs for projects common to both the PG&E and ORA are averaged.⁸⁵ For large pipes, PG&E did not provide cost data for projects on lines other than L-109, so the ORA revised forecast uses PSEP Report cost data including nine additional large pipe projects. Figure 3 below compares the ORA revised forecast to its original forecast and the PD values:⁸⁶

Figure 3 – Comparison of ORA Forecasts to PD

Proposal	2015	2016	2017	Total
ORA, as filed	\$ 110,320	\$ 109,670	\$ 103,130	\$ 323,120
PD	\$ 164,534	\$ 168,320	\$ 172,696	\$ 505,550
ORA Alternative	\$ 143,646	\$ 146,950	\$ 150,770	\$ 441,366
Change, ORA-Alt. less PD	\$ (20,888)	\$ (21,370)	\$ (21,926)	\$ (64,184)

The alternative forecast offered by ORA, which is based on three pipe groupings rather than two, differs from ORA’s original forecast in three ways:

1. Unit costs use PG&E discovery data rather than PSEP Report data where it is available;
2. Large pipe unit costs are applied to 24” diameter GT&S projects; and
3. Application of PD values for 2015 escalation and 2016-2017 attrition are included.

The second adjustment addresses the 24” pipe discrepancy noted in the PD.⁸⁷ ORA’s original analysis applied the medium pipe unit cost to 24” GT&S projects based on PG&E’s detailed

⁸⁴ Ex ALJ-1, file “PD Vintage Pipe Replacement – Capital.xls,” Column E.

⁸⁵ See Ex. ORA-131, tab “ITD cost, no betterment”, cells E22 and E45.

⁸⁶ ORA’s as-filed forecast did not include escalation or adjustment for attrition. See Ex. ORA-34, pp. 54-55. The alternative forecast uses the same escalation and attrition adjustments as the PD.

⁸⁷ PD, p. 82.

cost calculator, which was internally consistent, rather than PG&E's unit cost workpaper, which was not internally consistent.⁸⁸

Based on the PD's conclusions, ORA reviewed the projects used to calculate the large pipe unit cost in Exhibit ORA-131 and found that a majority were 24" in diameter. ORA applied the large pipe unit cost to 24" pipe, and it calculated the alternative forecast shown above to reflect this.

ORA's "alternative" forecast outlined here should be adopted because it is consistent with the PD's conclusions criticizing PG&E's reliance solely on Line 109 costs for its large diameter forecast, it corrects the arbitrary combining of large and medium pipes by providing a forecast based on the three pipe groupings in the record of this proceeding, and it corrects the unit cost assigned to 24" pipe.

ORA supports this forecast, even though it is significantly higher than its original forecast and fails to take into account the falling costs of the VPR Program over the rate case period, in order to ensure that PG&E does not scale back its proposed scope of work. PG&E has stated that it "plans to perform as much hydrostatic testing that it can, based on risk, given the dollar amount that is approved in this rate case."⁸⁹ While this quote refers to hydrostatic testing, its implication likely applies to VPR as well: PG&E does not want to be held accountable for meeting its proposed scope targets if the Commission does not adopt its expenditure forecast.

The ORA revised forecast is at the high end of reasonable, and should ensure that PG&E has sufficient funds to pursue its proposed scope of work and to protect public safety. Overcollections due to smaller scopes of work in less populated areas in 2016 and 2017 should mitigate against the unlikely event of undercollections in 2015.

Finally, as Indicated Shippers discussed in depth in their opening brief, PG&E cannot estimate or characterize the reduction in risk achieved by the VPR program.⁹⁰ PG&E's witness admitted that over 90% of the potentially impacted population that this program would address are already protected against the threat addressed and that over 99.8% would be addressed by the end of

⁸⁸ TURN's Opening Brief, p.132-133, explains that PG&E's unit cost workpaper, Exhibit PG&E-5, p. WP 4A-722, had issues: "the definition of "24-30" [for large pipes] makes little sense [since] (there are pipelines greater than 30 inches.)" In addition, this workpaper has an inaccurate heading of "years" and includes geographic definitions that do not include the full scope of either PSEP or VPR projects. See PD, Table 7, p. 70.

⁸⁹ PG&E Opening Brief, p.7-30.

⁹⁰ IS OB, pp. 122-123.

2017.²¹ Consequently, decreases in the PD’s approved forecast for this program should not impact public safety. For all of these reasons, ORA’s revised forecast is reasonable and should be adopted.

4. The PD Errs by Failing to Require Modifications to the Quarterly PSEP Compliance Reports

The *PSEP Decision*, D.12-12-030, required PG&E to file Quarterly PSEP Compliance Reports (Reports) “to keep the Commission, the parties, and the public informed of PG&E’s progress and actual cost experience” with its pressure test and pipe replacement programs.²² The PSEP Decision clearly anticipated that all PSEP costs would be identified in the Reports since they were intended to provide information regarding PG&E’s “actual cost experience.” Further, given the PSEP Decision’s requirement that the Reports include “comparisons of actual versus authorized cost for each work project as well as explanations of any significant deviations”²³ it is evident that the data was intended to be used, among other things, for audits, for forecasting the costs of future pressure test and pipe replacement costs, and for identifying opportunities for cost savings and other efficiencies.

While the PD acknowledges the value of the Reports by continuing to require them in Conclusion of Law 29, the PD errs by failing to acknowledge the record of deficiencies in the Reports established in this case.²⁴ Among other things, PG&E omitted millions of dollars in PSEP “program” costs from the Reports, in violation of D.12-12-030. At a minimum, Conclusion of Law 29 should be modified as set forth in Appendix A to remedy these deficiencies going forward and to include reporting of not only pressure test costs, but also pipe replacement and ILI costs. Further findings and conclusions should also be made, as set forth in Appendix A, regarding the purpose of the Reports, and the need for accurate reporting by PG&E. Finally, a Working Group should be created to establish the format and content requirements for future Reports to ensure they are useful to all interested parties.

²¹ 20 RT 2300 through 2302.

²² PSEP Decision, p. 83, OP 10, and Attachment D.

²³ PSEP Decision, p. 83.

²⁴ ORA OB, pp. 50-58.

5. Public Awareness

The PD errs in Table 12⁹⁵ by using PG&E's direct testimony values⁹⁶ rather than PG&E's rebuttal testimony values which superseded and replaced the direct testimony values.⁹⁷ The PD uses recorded 2012 and 2013-2014 forecast expenses, while PG&E's rebuttal includes 2013 recorded expenses. Using the three-year average of 2012-2013 recorded and 2014 forecast expenses, and then removing the 2014 forecast of approximately \$5.3 million for PG&E's commitment to Congresswoman Jackie Speier, as adopted in the PD, results in a 2015 average spending level of \$3.0 million, \$0.6 million less than the \$3.6 million set in the PD.

The PD repeats this error in Ordering Paragraph 49:⁹⁸ PG&E's forecast expenses for the Public Awareness Program should be reduced by \$3.558 million. This would result in PG&E authorized Public Awareness expenses of \$0.8 million. A corrected Ordering Paragraph 49 should state that PG&E's Public Awareness Program is reduced to \$3.0 million for 2015.

D. Corrosion Control

1. The PD Errs By Neglecting Record Evidence Showing that Corrosion is A Time-Dependent Threat That Gets Worse Over Time

The PD errs in finding that "there is no testimony to conclude that the corrosion problems with the 335 contacted casings would have been smaller if PG&E had remediated them sooner."⁹⁹ On the contrary, the PD's discussion on Corrosion Control immediately **defines** corrosion "as a 'time dependent' threat that occurs over time."¹⁰⁰ PG&E defines corrosion under Time-Dependent Threats, meaning that "the **threat level may grow over time if unchecked**" and specifically lists external corrosion, internal corrosion, and stress corrosion cracking in the Time-Dependent Threat category.¹⁰¹ PG&E stated the "American Society of Mechanical Engineers (ASME) B31.8S classifies corrosion as a "time-dependent" threat because it occurs and can become more aggressive

⁹⁵ PD, p. 91, Table 12.

⁹⁶ Ex. PG&E-1 at 4A-77, Table 4A-25.

⁹⁷ Ex. PG&E-58 at 4A-94, Table 4A-14.

⁹⁸ PD p. 416, OP 49.

⁹⁹ PD, Finding of Fact 88, p. 396.

¹⁰⁰ PD, p. 147.

¹⁰¹ Ex. PG&E-1, p. 2-20. (Emphasis added).

over time.”¹⁰² Corrosion has been of concern for natural gas pipelines going back to at least 1955, where periodic inspection was required to determine if corrosion control methods were working.¹⁰³ PG&E justifies the rapid pace of its newly-proposed contacted casings program as “appropriate to address the risk because contacted casings could be experiencing unmitigated active external corrosion which compromises transmission pipeline integrity.”¹⁰⁴

The Exponent Phase 1 report finds violations of federal regulations, which are discussed in the Proposed Decision.¹⁰⁵ For example, Exponent found that parts of Line 138A and 138B were not regularly inspected for atmospheric corrosion, in violation of 49 CFR 192.481, which requires inspection of onshore pipeline at least once every three calendar years.¹⁰⁶

Under the standard of proof identified in the Proposed Decision, “[c]osts are just and reasonable when they ‘have been prudently incurred by competent management exercising the best practices of the era, and using well-trained, well-informed and conscientious employees and contractors who are performing their jobs properly.’”¹⁰⁷ Based on the necessity of ensuring that operators conduct appropriate maintenance on their systems, the disallowances proposed by ORA, TURN, and Indicated Shippers are appropriate. The PD acknowledged that PG&E’s own consultant, Exponent, in their Phase 1 and 2 reports clearly indicated that PG&E’s corrosion control programs were deficient in comparison to industry “best practices”¹⁰⁸ and that PG&E was not providing employees the necessary training¹⁰⁹ or information¹¹⁰ to perform their jobs correctly.¹¹¹

¹⁰² Ex. PG&E-1, p. 7-8, lines 12-14.

¹⁰³ Ex. ORA-153, Corrosion is referenced in sections 851.2, 851.3, and 851.4, at pages 76 & 77.

¹⁰⁴ Ex. PG&E-1, p. 7-36, lines 29-33.

¹⁰⁵ PD, p. 191.

¹⁰⁶ Ex. TURN-52, p. E-4.

¹⁰⁷ PD, p. 20.

¹⁰⁸ PD, p. 174.

¹⁰⁹ Ex. ORA-69, pp. 29-30, and Ex. TURN-52.

¹¹⁰ Ex. TURN-52, which identified lack of asset information relating to Atmospheric Corrosion (p. 16) and overall Data Management (p. 31).

¹¹¹ Ex. TURN-52, pp. 50-57.

2. The PD errs in Relying Upon Purported PG&E “Self-disallowances” of Atmospheric Control Costs - For Which PG&E Refused to Provide Any Support to Justify - Granting PG&E Its Full Cost Request

The PD concluded that PG&E’s proposed atmospheric control costs were not intended “to remediate past work that was originally performed incorrectly.”¹¹² Even though the PD acknowledged that the “Exponent Phase 2 Report did find... PG&E was non-compliant with federal regulations in certain instances”¹¹³ it also noted that “PG&E has excluded costs associated with non-compliance” ¹¹⁴from recovery.

However, PG&E has refused to provide **any** support for any of the excluded costs of \$22 million. Because consideration of these purported “excluded” costs has been used to justify granting higher revenue requirements, they are equivalent to requests for an increase in revenue requirement, and thus require some indicia of proof besides PG&E’s “word.” The PD failed to even acknowledge this argument despite multiple parties raising it, which is arbitrary and capricious decision making. The Commission should reduce the PD’s award for atmospheric corrosion control costs by the amount PG&E has claimed to have excluded from the rate case given PG&E’s refusal to provide corroborating documentation.

E. REVENUE REQUIREMENT ISSUES

ORA has identified in its review of the PD and Appendices numerous discrepancies that lead to material differences between the PD and the Results of Operations model runs. Areas where ORA has identified errors include Appendix D: Table 1, where adopted adjusted amounts for Direct Assessment has disallowances of \$20 million, but Appendix D – Table 1 shows a disallowance of \$23 million. The PD incorrectly allocates the Costs for Manage Buildings of \$18.493 million, which should be \$13.356 million instead based on D.14-08-032.¹¹⁵

The PD also errs by reducing the disallowance associated for the delay in the proceeding due to PG&E’s improper ex parte contacts to account for the penalties PG&E is paying in association

¹¹² PD, p. 191.

¹¹³ PD, p. 191.

¹¹⁴ PD, p. 191.

¹¹⁵ D.14-08-032, p. 123.

with the San Bruno disaster.¹¹⁶ Application of the San Bruno penalties should not affect the amount of the ex parte disallowance.¹¹⁷

F. RATE ISSUES

ORA reserves its comments on Rate Issues for the supplemental comments on June 1, 2016 pending PG&E's data response.

G. ORA's Gas Safety Motion for an Order to Show Cause

On December 16, 2015, ORA filed a Motion for an Order to Show Cause and other relief based on a comprehensive showing that PG&E is not in compliance with Minimum Federal Safety Standards and Public Utilities Code § 958 ("Gas Safety Motion"). The Commission has taken no action on these safety concerns. The PD denies the Gas Safety Motion with no comment.¹¹⁸ The Commission's failure to consider the serious issues raised by the Gas Safety Motion is legal error. Among other things, the Commission has a legal duty under federal law to enforce the Minimum Federal Safety Standards. Failure to comply with this legal duty could result in a loss of federal enforcement funding, as well as a loss of enforcement jurisdiction. At a minimum, the PD should identify where, when, and how the Commission intends to address the issues raised in the Gas Safety Motion regarding PG&E's failure to comply with state and federal laws and regulations.

H. \$850 Million in Disallowances

Consistent with the San Bruno Fines and Remedies Decision, D. 15-04-024, the Commission should not determine the adjusted revenue requirement of this proceeding until after the determination of the appropriate revenue requirement based on the merits of this proceeding.¹¹⁹ ORA recommends a schedule that allows for 1 month for comments, after the current decision is adopted, along with the provision of final rate tables and the results of operations model. Until the final decision is adopted in this proceeding, it is not possible to address the concerns raised in D.15-04-024 that "[a]ccordingly if this Commission disallows, or limits, any proposed safety-related expenditure by PG&E, in the current GT&S or subsequent proceeding ... such disallowances may

¹¹⁶ Comparing line 37 of Appendix C: Table 1 and line 37 of Appendix G: Table 3. \$164,003 thousand is reduced to \$102,251 thousand, or approximately \$62 million less in penalties.

¹¹⁷ The PD adopts a base revenue requirement of \$1,108 million before the ex parte disallowance.

¹¹⁸ PD, pp. 384-385.

¹¹⁹ D.15-04-024, pp. 94-98.

not be booked into the Shareholder-Funded Account.”¹²⁰ Given the errors identified in these comments, the disallowances cannot be appropriately determined until after the decision is finalized.

IV. CONCLUSION

For all the foregoing reasons, ORA asks that the Commission adopt and incorporate the changes proposed above and in Appendix A into its final decision in this proceeding.

Respectfully submitted,

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¹²⁰ D.15-04-024, pp. 98.

APPENDIX A

PROPOSED REVISIONS TO PROPOSED DECISION TEXT, FINDINGS OF FACT AND CONCLUSIONS OF LAW, AND ORDERING PARAGRAPHS

ADDITIONS IN RED UNDERLINE / DELETIONS IN ~~STRIKEOUT~~

PROPOSED REVISIONS TO PD TEXT:

PD pp. 52-53:

ORA next contends that PG&E did not take into consideration the downward trend in hydrotest costs between 2011 and 2013 due to efficiency gains, and changes in the nature of the hydrotest program that will result in further efficiency gains during the rate case years. ~~It~~ ORA further notes that the project lengths during the Rate Case period are projected to be ~~similar~~ substantially longer in length ~~to~~ than the projects conducted in 2013.

PROPOSED REVISIONS TO FINDINGS OF FACT (FOF)

Add the following new FOFs after FOF 1:

The risks identified, and for which PG&E is proposing mitigation programs in this rate case period, are not new.

PG&E has not provided estimates of the amount of risk that will be reduced by the proposed projects in this proceeding.

For the top 7 transmission risks and top 7 storage risks, PG&E had to adjust the Financial score for 11 of the 14 risks.

PG&E chose the risk model to stay consistent with its overall corporate weighting system.

3. This is the first GT&S case where PG&E is required to develop a revenue requirement explicitly based on risk. PG&E did not develop a revenue requirement in this proceeding explicitly based on risk, primarily because PG&E's model does not measure risk in monetary terms.

Add the following new FOFs after FOF 3:

PG&E's risk model in this proceeding is not substantially different than the filing it made in the 2014 General Rate Case.

PG&E provided weightings in determining its priority of risks with Health and Safety rated 30%, Financial Consequences 30%, Reliability 25%, Environment 5%, and Regulatory Compliance 5%.

PG&E's weightings mirror its Short Term Incentive Plan.

PG&E's risk tools cannot quantitatively measure risk reduction.

PG&E's risk models do not allow determination of incremental risk reduction values for various risk mitigation programs.

Add the following new FOFs after FOF 14:

PG&E's average digs per project from 2004-2013 is 5.78.

PG&E's average digs per project from 2008-2013 is 4.43.

19. PG&E has ~~confirmed~~ represented that ratepayers will not bear the costs of testing the post-1961 miles of pipe for which PG&E does not have strength test records.

Add the following new FOFs after FOF 19:

PG&E's requested hydrotest unit cost in this case is double its request for PSEP.

The Commission found that PG&E's PSEP unit cost was "at the high end of the range of reasonableness" in D.12-12-030.

ORA's 2015 forecast of hydrotest costs per mile is comparable to the unit cost adopted for the PSEP program in D.12-12-030.

PG&E's proposed unit cost for 2015 of \$1.02 million per mile is equal to PG&E's forecast cost for 2013 of \$970,000 per mile, plus escalation.

Approximately 92% of the costs relied upon in PG&E's 2013 hydrotest unit cost forecast were forecasted costs.

PG&E's recorded cost data for 2013 results in a unit cost of \$840,000 per mile, more than 15% less than PG&E's forecast.

PG&E provided an estimate for 2015 hydrotest unit costs of \$1.86 million per mile. This estimate exceeds the actual annual unit costs for every year of the PSEP program.

Prior to 2014, PG&E's hydrotest costs per mile decreased each year. PG&E's 2014 costs per mile increased due to the number of short "clean-up" projects completed.

The proposed scope of the pending hydrotest program includes 153 projects, only four of which are shorter than 600 feet.

In the PSEP proceeding, PG&E established a minimum length for hydrotesting of 600 feet, below which PG&E proposed replacement in lieu of hydrotesting as a more cost effective mitigation.

Longer hydrotests have lower unit costs since high fixed costs are amortized over a greater number of miles tested.

Hydrotest costs per mile should decline over the rate case period due to opportunities for PG&E to increase the efficiency of the testing process, and due to the longer length of projects in the current case compared to the 2011-2013 PSEP program.

PG&E's Quarterly PSEP Compliance Reports omitted over \$100 million of costs PG&E recorded for the PSEP program. A majority of these costs were unique to PSEP and unlikely to be incurred in the ongoing hydrotest program addressed in the current rate case.

24. PG&E expects to replace 60 miles of vintage pipe during the Rate Case Period, focusing on the areas with the greatest population density in 2015 and then decreasing in density in 2016 and 2017.

33. ORA determined that absent any counteracting trends that would reduce project costs, the escalation rate for 2015 should be approximately 4.4%.

Add the following new FOFs after FOF 33:

Annual costs for the VPR program are highly variable because they depend on the quantity of pipeline replaced, the diameter of that pipeline, and its location.

Exhibit ORA-131 provides calculations for "Large OD" pipes which includes nine 24" PSEP projects from lines other than Line 109.

ORA's analysis of the PSEP Quarterly Compliance Reports demonstrated that PG&E omitted certain costs for the PSEP hydrotest and pipe replacement programs in those Reports.

The value of data provided in PG&E's PSEP Quarterly Compliance Reports was compromised by PG&E's failure to report certain costs, and by other issues raised by ORA.

84. PG&E claims it is not seeking ratepayer funding for expenses and capital expenditures to perform corrective work in the AC Interference Program for noncompliance with of 49 CFR 192.473, but it did not provide any evidence in support of this assertion.

Add the following new FOF after FOF 87:

The American Society of Mechanical Engineers (ASME) B31.8S classifies corrosion as a “time-dependent” threat because it occurs and can become more aggressive over time.

~~88. There is no testimony to conclude that the corrosion problems with the 335 contacted casings would have been smaller if PG&E had remediated them sooner.~~

~~93. The Exponent Phase 1 and Phase 2 reports do not find any violations of federal regulations, but rather deficiencies in PG&E’s documentation and guidelines for internal corrosion inspection, monitoring and mitigation.~~

Add the following new FOF after FOF 93:

The Exponent Phase 1 report found lack of knowledge/training as a barrier for cathodic protection, casings, interference, atmospheric corrosion, internal corrosion, work management, training, and operator qualification.

The Exponent Phase 1 report found PG&E lacked centralized accurate data and asset information for corrosion control.

The Exponent Phase 1 report found violations of federal regulations and deficiencies in PG&E’s documentation and guidelines.

REVISIONS TO CONCLUSIONS OF LAW (COL)

Add the following new COL after COL 1:

Commission Decision 82-12-055 found that the utility's recovery of deferred maintenance expense would establish an undesirable precedent, whereby the utility is effectively guaranteed that it can earn (or exceed) its authorized rate of return, regardless of its operating efficiency or inefficiency, simply by curtailing current maintenance activities, in assurance that it could be refinanced later through recovery of deferred maintenance expenses in a succeeding rate case. The Decision denied cost recovery for deferred maintenance on the basis that this would create a perverse incentive for the utility to defer needed maintenance into the future.

~~2. PG&E's forecast costs are not unreasonable and subject to ratemaking disallowance simply because its management imprudently delayed or deferred work.~~

~~4. PG&E's risk management process provides a framework for purposes of evaluating the reasonableness of PG&E's forecast revenue requirement in this GT&S proceeding~~

Add the following new COL after COL 4:

The Safety and Enforcement Division's Final Staff Report (Staff Report) is incorporated into this proceeding as a reference document.

Many of the concerns Indicated Shippers has raised concerning PG&E's risk management process will be considered within the scope of PG&E's S-MAP application. We should not prejudge those issues here.

Commission Decision 14-08-032 found that the expectations created in the Executive Director's March 5, 2012 letter anticipate a use of risk assessment that is beyond what one currently finds in the industry. Such a risk assessment is still beyond what one currently finds in the industry, including PG&E's risk-based filing in this application.

~~5. PG&E's proposed risk management approach and asset family categories are reasonable.~~¹²¹

~~16. PG&E's forecast ECDA expenses should be reduced to reflect a digs-to-project ratio of 6.02~~4.50, to reflect PG&E's actual experience from 2008-2013.

~~19. PG&E's 2015 forecast hydrotest capital expense of \$0.97 million per mile is reasonable and should be adopted.~~

¹²¹ In the alternative, this COL could be entirely eliminated as it is not a finding on a material issue in this proceeding.

Add the following new COLs after COL 19:

2013 recorded costs are a more accurate source for determining hydrotest unit costs than forecast costs.

TURN's 2015 hydrotest unit cost forecast of \$.84 million per mile, which is based on actual 2013 costs, is reasonable and should be adopted.

26. Consistent with its representations in this proceeding and our determinations here and in D.12-12-030, PG&E should not recover from ratepayers the costs to pressure test post-1961 miles of pipe for which PG&E does not have strength test records and steps should be taken to confirm that these costs are not charged to ratepayers.

Add the following new COLs after COL 28:

The PSEP Decision, D.12-12-030, intended that all PSEP program costs be included in Quarterly PSEP Reports in order to facilitate transparency regarding PG&E's pressure test and pipe replacement costs, with the implication that the data could be used, among other things, for audits and for forecasting the cost of future pressure test and pipe replacement costs.

PG&E's failure to include all actual costs in the PSEP Compliance Reports violates the clear intention of the Commission in D.12-12-030.

29. PG&E should be required to file quarterly compliance reports of its transmission pipeline hydrotest work, including pressure test, pipe replacement, and ILI. The reports should include all costs recorded to these programs such that they provide an accurate and complete record of all costs at the project and program level. The reports ~~shall~~ should generally follow the format in Attachment D of the *PSEP Decision*, revised to reflect the projects proposed for the Rate Case Period, but should be subject to additional revisions as determined by a working group. PG&E's first compliance filing shall cover the period between January 1, 2015 and the quarter in which this Decision is issued, and shall be due no later than 30 days after the end of the quarter.

Add the following new COL after COL 29:

A working group should be created for the purpose of establishing formatting and content requirements to ensure that future Quarterly Reports are useful to parties. The working group should investigate the value of including in the Reports additional data on costs for activities that are driving program costs and should be empowered to require additional information in the Reports that it determines would be useful to the parties, such as cost drivers, if the working group determines that such information can be obtained.

35. Pipe diameter size, does not appear to be a screen for selecting projects, but rather the method for grouping costs. Analysis by both ORA and PG&E shows that pipe replacement costs are relatively independent of diameter for pipelines less than 24" in diameter.

39. Unit costs for vintage pipeline replacement should be based on the PSEP project costs identified in Exhibit ORA-131. Overlapping (common) projects used by both PG&E and ORA in their analyses should be used to determine unit costs for projects that involve pipe less than 24". All projects, including those on lines other than Line 109, should be used to determine unit costs for projects that involve pipe 24" and larger. ~~as identified in Exhibit ORA-131.~~

41. VPR projects should be assigned to one of the following three size classifications established by PG&E for the purpose of estimating project costs: Small pipes (<12" diameter); Medium pipes (≥12" to <24" diameter); and Large pipes (≥24" diameter). Given the discrepancy between PG&E's definition of Medium Diameter Pipe in the Unit Cost Analysis and the Cost Calculator, and the large number of projects that involve 24" pipe, there is a risk that if separate unit costs were adopted for Medium Diameter and Large Diameter pipe, the costs would not properly reflect the work to be performed.

42. ~~It would be reasonable to average the unit costs for Medium Diameter and Large Diameter pipe and adopt a unit price of \$7.985 million/mile for all pipe 12" or greater.~~

43. The unit prices for vintage pipeline replacement should be \$4.51 million per mile for all pipe with diameter less than 12," \$3.67 million per mile for all pipe with diameter of 12" or greater, but less than 24," and ~~\$7.985~~ \$7.25 million per mile for all pipe with diameter of 12"24" or greater.

108. ~~It would be unreasonable to conclude that none of PG&E's past corrosion control work had been performed properly and that if it had been, no future ongoing corrosion control work would be needed.~~

Add the following new COL after COL 111:

The Commission cannot adopt PG&E's self-identified exclusions without record evidence in support of such exclusions.

296. ~~If the proposal for allocation of the \$850 million penalty adopted in the *Penalties Decision* contained in Appendix G were adopted, there would not be a need for a second decision to address this allocation and PG&E's rates could go into effect upon the filing of a Tier 1 Advice Letter.~~

297. ~~Parties should comment on the proposal to allocate the \$850 million disallowance as part of their comments on the Proposed Decision.~~

298. ~~Parties advocating for a second decision should include in their comments the specific factual issues that need to be addressed and a proposed schedule.~~

PROPOSED REVISIONS TO ORDERING PARAGRAPHS (OPs)

2. ~~Pacific Gas and Electric Company's proposed risk management approach and asset family categories are adopted for use in this gas transmission and storage application.~~

4. Pacific Gas and Electric Company shall file quarterly compliance reports of its hydrotest work, including hydrotest, pipe replacement, and ILI. The reports will include all costs recorded to these programs such that they provide an accurate and complete record of all costs at the project and program level. The reports shall generally follow the format in Attachment D of Decision 12-12-030, revised to reflect the projects proposed for the Rate Case Period, but subject to additional revisions as determined by the working group established pursuant to Ordering Paragraph ____ below [new OP]. Additional data may be required in the reports to disclose cost-drivers, if the working group determines that useful information can be obtained. PG&E's first compliance filing shall cover the period between January 1, 2015 and the quarter in which this Decision is issued, and shall be due no later than 30 days after the end of the quarter.

New Ordering Paragraph To Add After OP 4:

A working group shall be created for the purpose of establishing formatting and content requirements to ensure the reports required by Ordering Paragraph 4, are useful to all parties. In addition, the working group shall investigate inclusion of additional data on costs for activities that are driving gas transmission program costs and is empowered to require reporting changes it determines are reasonable, with authorization from the Commission's Executive Director. The working group shall meet for the first time within 15 days of the adoption of this decision.